APPARATUS AND METHODS FOR ACOUSTICALLY DETERMINING FLUID PROPERTIES WHILE SAMPLING

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] Not applicable.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH

[0002] Not applicable.

FIELD OF THE INVENTION

[0003] The present invention relates to an apparatus and method for acoustically analyzing a fluid sample. More particularly, the present invention relates to an apparatus and methods for acoustically determining various properties of a fluid sample at *in situ* conditions.

BACKGROUND OF THE INVENTION

[0004] Density is the fundamental physical property that can be used alone or in conjunction with other properties to characterize fluids in many industrial processes, such as in the petroleum, chemical and food industries. Laboratory measurements of density can reach accuracies of .01% or less, if sufficient care is taken during the transportation and analysis of the fluid sample.

[0005] Various methods of measuring the density of a fluid have been proposed however, are not well suited for *in situ* use. For example, many conventional densitometers are limited by their physical construction if the acoustic transducer(s) are affixed directly to

the fluid sample chamber. When the chamber is subjected to extreme *in situ* pressure, the chamber dimensions may be affected thus, requiring recalibration of the device with each change in the fluid sample pressure. The net effect is a greater degree of uncertainty in the density measurements taken. Various other density measurement devices have been developed to maximize precision while reducing material complexity as discussed in Vol. 49, No. 9, of the September 2002 issue of *IEEE Transactions On Ultrasonics, Ferroelectrics, and Frequency Control,* titled *Ultrasonic Densitometer Using a Multiple Reflection Technique* by Ricardo Tokio Higuti and Julio Cezar Adamowski. The accuracy of these devices, however, is also limited by temperature and pressure conditions of the fluid sample, which may alter the dimensions of the device. As a result, these devices may require excessive recalibration with each fluid sample and/or may present unacceptable results at extreme pressures.

[0006] Another common ultrasonic method used to measure the density of fluids is based on the measurement of the reflection coefficient at the interface between a reference material and the fluid sample as more fully described in U.S. Patent Nos. 5,708,191 and 5,886,250. The '191 and '250 patents each describe methods for determining the density of a fluid sample by means of a material wedge positioned in the fluid. The material properties of the wedge are limited to materials having an acoustic impedance no greater than eleven (11) times that of the fluid sample. These methods are therefore, limited by their material requirements, which may be wholly inappropriate for certain fluids and at *in situ* conditions.

[0007] In the petroleum industry, reservoirs are usually several thousands of feet from the earth's surface and are typically under extreme pressures reaching several tens of thousands of pounds per square inch. Geothermal temperatures at these depths are on the order of 250° F or more. Most conventional tools and associated methods are therefore, either inappropriate or impractical for taking density measurements of formation fluid samples from the earth at *in situ* temperatures and pressures. Consequently, formation fluid samples taken by conventional means, such as by a wireline device, are normally shipped to a laboratory where, under controlled conditions mimicking *in situ* pressure and temperature, density and other properties may be determined. The fluid properties may substantially impact decisions as to whether production may be economically achieved and, if so, the duration, expense and unit price of such production.

[0008] Transfer of the formation fluid sample to the surface environment, however, may induce several irreversible changes in the fluid sample. For example, during the rise of a fluid sample to the surface, both pressure and temperature drop substantially. Pressure and temperature changes may cause certain components of the fluid sample to irreversibly precipitate from solution and/or colloidal suspension, causing the fluid sample to be underestimated by surface testing. Production events such as paraffin or asphaltene deposition may also be avoided by preservation of the formation fluid sample at *in situ* conditions. For these reasons, preservation of the *in situ* state of a fluid sample during testing is preferred over mimicking *in situ* conditions.

[0009] One example of a conventional wireline sampling device that addresses this issue is illustrated in U. S. patent application serial number 10/242,112, published on April 10, 2003 and incorporated herein by reference. The '112 application describes a device or tool for maintaining the single phase integrity of a deep formation well sample that is removed to the surface for testing. Referring to FIG. 1 of the '112 application, the sampling and measuring instrument (tool) **13** is positioned within borehole **10** by winding or unwinding cable **12** from hoist **19**, around which cable **12** is spooled. Depth information from depth indicator **20** is coupled to signal processor **21** and recorder **22** when instrument **13** is disposed adjacent an earth formation of interest. Electrical control signals from control circuits **23** are transmitted through electrical conductors contained within cable **12** to instrument **13**. The sampling mechanism or tool **13** is comprised of a hydraulic power system **14**, a fluid sample storage section **15**, and a sampling mechanism section **16**. Sampling mechanism **16** includes a selectively extensible well wall engaging pad member **17**, a selectively extensible fluid admitting sampling probe member **18**, and bi-directional pumping member **19**. Within the sample storage section **15** are one or more sample accumulation chambers **30**. FIG. 2 schematically illustrates a fundamental configuration of accumulation chamber **30**. While improving on the preservation of *in situ* conditions of the fluid sample, this tool does not address other problems associated with analyzing the formation fluid sample at a lab, such as:

i) limitations on the available number of fluid samples using conventional wireline devices;

ii) transport delays;

iii) deterioration of fluid samples by improper handling and conditioning;

iv) delayed use of test results for field appraisal (hydrocarbon potential) and well planning;

v) limitations on lab conditions and instruments; and

vi) export restrictions.

[0010] Some fluid properties, however, may be analyzed *in situ* as illustrated in U.S. Patent No. 6,683,681 B2, issued January 27, 2004 and incorporated herein by reference. The '681 patent describes an apparatus and method for measuring the refractive index of fluids along a continuum, for measuring attenuated reflectance spectra, and for interpreting the measurements made with the apparatus to determine a variety of formation fluid parameters. This device, however, may require more complex and sophisticated equipment than is necessary or desired to determine certain physical parameters of a formation fluid sample—particularly acoustic velocity.

[0011] Other conventional techniques may propose an estimated or simulated pressure, volume and temperature (PVT) of the fluid sample based upon pressure gradients and geochemical parameters of the fluid sample *in situ*. Conventionally proposed index and/or estimate techniques may be limited, however, by the physical properties of the fluid sample that must be analyzed and their accuracy, which may depart as much as 10-15% from laboratory values.

[0012] There is, therefore, a need for a device capable of accurately determining fluid properties such as velocity, volume, density, compressibility and viscosity with nominal

calibration at *in situ* conditions. Additionally, there is a need for a device that is simple, efficient, and easily incorporated into conventional wireline fluid sampling tools or any downhole sampling device. Finally, such a device should also be capable of analyzing similar fluid properties in other industries.

SUMMARY OF THE INVENTION

[0013] The present invention therefore, provides an apparatus for acoustically analyzing a fluid sample comprising a chamber, a transmitter positioned within the chamber for transmitting an acoustic signal through the fluid, a reflector movably positioned within the fluid for reflecting the acoustic signal, and a receiver positioned within the chamber for detecting reflections of the acoustic signal.

[0014] In another embodiment, the present invention provides a method for acoustically analyzing a fluid sample in a chamber using a transmitter, a substantially stationary reflector positioned within the fluid, and a receiver. The method comprises the steps of transmitting an acoustic signal from the transmitter through the fluid and detecting reflections of the acoustic signal from the reflector at the receiver. In another embodiment, the present invention provides a method for acoustically analyzing a fluid sample in a chamber using a transmitter, a reflector moveably positioned within the fluid and a receiver. The method comprises the steps of transmitting acoustic signals from the transmitter through the fluid and detecting reflections of the acoustic signals from the reflector at the receiver as the reflector moves.

BRIEF DESCRIPTION OF THE DRAWINGS

[0015] The present invention is described with reference to the accompanying drawings in which, like reference numbers indicate identical or functionally similar elements.

[0016] FIG. 1 is a schematic illustration of the formation fluid sampler and cooperative devices illustrated in FIG. 1 of the '112 application.

[0017] FIG. 2 is a schematic sectional view of one embodiment of a formation sampling tool described in reference to FIG. 2 of the '112 application.

[0018] FIG. 3 is a partial elevational view illustrating one embodiment of the present invention and its related components.

[0019] FIG. 4A is a cross-sectional side view of the reflector illustrated in FIG. 3 along line 4A-4A.

[0020] FIG. 4B is a cross-sectional side view of another embodiment of the reflector shown in FIG. 4A.

[0021] FIG. 5 is a flowchart illustrating one method of the present invention.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0022] In the oil and gas industries, large sums of money are spent in order to locate hydrocarbon deposits and determine the hydrocarbon production potential of a known reservoir. In this quest to locate hydrocarbons and estimate their potential, exploration wells are utilized. These wells may also be used to determine other properties of the

hydrocarbons, which are present. Often the design specification and material costs used to construct these wells is dependent on the properties of the hydrocarbons such as gas/oil ratios, viscosity, compressibility, bubble point pressure, volume, velocity and density.

[0023] Conventionally, wireline formation testing tools, such as the Baker Atlas Reservoir Characterization Instrument illustrated in FIG. 1 may be used to sample formation fluids drawn from a formation through an exploration well. Initially, fluids that are withdrawn may be highly contaminated by filtrates of the fluids ("muds") that were used during drilling. To obtain samples that are sufficiently clean (usually less than 10% contamination) so that the sample will provide meaningful lab data concerning the formation, formation fluids are generally pumped from the wellbore while clean up is being monitored in real time. Then, these withdrawn fluids can be collected downhole in tanks for subsequent laboratory analysis at the surface. Measuring instruments in the wellbore environment must therefore, operate within a limited space and under extreme conditions, including elevated pressures, temperatures, vibration and shock.

[0024] The present invention proposes such an instrument for determining one or more properties of a fluid sample, which may be used in a laboratory environment and/or incorporated into conventional wireline fluid sampling tools for *in situ* use.

[0025] Referring now to FIG. 3, one embodiment of an apparatus is illustrated for acoustic analysis of a fluid sample. The apparatus comprises a chamber **300** for the sample fluid. The chamber **300** comprises a sealed first end **302**, a piston **304** slidably disposed within a second end **306** of the chamber **300** and a conduit **308** for introducing

the fluid into the chamber **300**. Those of ordinary skill in the art will appreciate that the conduit **308** is merely one of many components that may be employed to charge the chamber **300** with a fluid sample to a predetermined pressure. The same conduit **308,** or another conduit (not shown) may be used to safely and controllably discharge the fluid sample from chamber **300**.

[0026] A servomotor **310** may be coupled to the piston **304** by one or more machine screws and is computer-controlled through a power/data cable **330** for driving the piston **304** and varying at least one of the pressure and temperature of the fluid within the chamber **300**. The piston **304** and chamber **300** may be thermally insulated to substantially maintain the pressure and/or temperature of the fluid within the chamber **300**.

[0027] A transmitter and a receiver are positioned within the chamber **300** for transmitting an acoustic signal through the fluid and detecting reflections of the acoustic signal, respectively. The transmitter and receiver may be rigidly mounted to the chamber **300** near the first end **302** and on the piston **304**, respectively, or vice versa. In one embodiment, the transmitter and the receiver are embodied in a single piezoelectric transducer **312**, which is supported within the fluid in the chamber **300** by a static piston **314** rigidly mounted to the chamber **300** near the first end **302**. A .5" diameter 1 MHz Valpey Fisher compressional wave acoustics transducer is preferred, however, any transducer may be used that emits an acoustic signal in a range from about .5 MHz to about 10 MHz. Because the transducer **312** is freely suspended in the fluid sample within the chamber **300**, there are no interface corrections required between the transducer **312**

and the fluid sample. The transducer may, alternatively, be positioned on the piston **304**, which permits continuous monitoring of the acoustic reflections compared to pressure variations starting from below reservoir pressure up to the pressure limitations of the chamber **300**. Other benefits may include early indication of sand entry and monitoring pump efficiency.

[0028] A reflector **316** is movably positioned within the fluid inside the chamber 300 for reflecting the acoustic signal and mixing the fluid. The reflector **316** is therefore, positioned opposite the transducer **312** relative to the piston **304**. The reflector may be ring-shaped as illustrated in FIGs. 3 and 4A or, alternatively, shaped like a disc as illustrated in FIG. 4B. In either embodiment, the reflector **316** comprises a first reflective surface **318** and a second reflective surface **320**. The reflector **316** also comprises a longitudinal opening **322** passing through the reflector **316**. The reflector **316** is substantially cylindrical in shape however, may comprise alternative shapes depending on the material requirements and design of the chamber **300**. The longitudinal passage **322** through the reflector **316** is stepped to create the second reflective surface **320** within the reflector **316**. A distance (D) is therefore, known upon the construction of the reflector **316**. The reflector **316** may be manufactured from any material having a sufficiently low coefficient of thermal expansion and a high bulk modulus including, for example, any non-corrosive metal or metal alloy to reduce any variation in distance (D) when the material is subjected to extreme temperatures and pressures within the chamber **300**.

[0029] Because the reflector **316** is freely suspended inside the chamber **300** and immersed in the fluid sample, it experiences only the isostatic compression of the fluid. Unlike the remainder of the components, it experiences no differential stresses. The reflectors bulk strain as a function of temperature and pressure is therefore, easily calibrated from its known material properties by techniques well known in the art. Thus, the material properties of the reflector **316** mitigate any variation in the distance (D) as the material is subjected to extreme temperatures and pressures within the chamber **300**.

[0030] In FIG. 4B, an alternative embodiment of the reflector is illustrated. The reflector **416**, like reflector **316**, is substantially cylindrical however, forms a disc without the longitudinal passage **322** illustrated in FIG. 4A. The reflector **416** also comprises a first reflective surface **418** and a second reflective surface **420**. The reflector **416** may also be manufactured from any material having a sufficiently low coefficient of thermal expansion and high bulk modulus.

[0031] A square wave pulsar/receiver **324** is electrically coupled with the transducer **312** through cable **330** for driving the same and processing the reflections of the acoustic signal. A Panametrics Model 5077PR square-wave pulsar/receiver is preferred, however, other commercially available pulsar/receivers may also be used. The pulsar/receiver **324** may be electrically coupled with the transducer **312** by means of high pressure electrical feed through connectors available from Kemlon Products and Development Company in Houston, Texas. The pulsar/receiver **324** preferably drives the transducer **312** in the pulse/echo mode. The pulsar/receiver **324** provides the radio frequency (RF) output and may be connected to an oscilloscope **326** through cable **330** for imaging the reflections of

the acoustic signal. Any commercially available oscilloscope may be used such as the Agilent Technologies 54657A 500 MHz oscilloscope.

[0032] A computer **328** may be used to operate the servomotor **310**, pulsar/receiver **324** and oscilloscope **326**. The computer **328** may include components comprising a processing unit, an operator interface, and a tool interface. The computer **328** may also comprise memory including a velocity calculation module, a volume calculation module, a density calculation module, and a reflector calibration module. The computer **328** may further comprise a bus that couples various system components including the memory to the processing unit. The computer **328** is only one example of a suitable computing environment and is not intended to suggest any limitation as to the scope of use or functionality of the invention. Furthermore, the computer **328** and oscilloscope **326** may be located at the surface of an earth formation when the apparatus is used within a wellbore and connected to the surface by means of a cable **330**. Alternatively, the computer **328** may have an oscilloscope, precluding the need for a separate oscilloscope **326**. Cable **330** may be constructed of any known type of cable for transmitting signals and/or power between the computer **328**, the pulsar/receiver **324** and/or the servomotor **310**. Alternatively, the computer **328** may be positioned below the surface, incorporated in the apparatus, positioned at a remote location, or positioned at any other convenient place.

[0033] The memory preferably stores various modules, which may be described as program modules containing computer-executable instructions executed by the computer **328**. The reflector calibration module contains computer-executable instructions

necessary to calibrate the reflector distance (D). The velocity calculation module includes computer-executable instructions necessary to calculate the acoustic velocity of the fluid sample at an *in situ* pressure. The volume calculation module includes computer-executable instructions necessary to calculate the volume of the fluid in the chamber **300**. And, the density calculation module includes computer-executable instructions necessary to calculate a density of the fluid. These program modules will be further described below in conjunction with the method of using the apparatus.

[0034] Generally, program modules include routines, programs, objects, components, data structures, etc. that perform particular tasks or implement particular abstract data types. Moreover, those skilled in the art will appreciate that the invention may be practiced with other computer system configurations, including hand-held devices, multiprocessor systems, microprocessor-based or programmable consumer electronics, minicomputers, mainframe computers, and the like. The invention may also be practiced in distributed computing environments where tasks are performed by remote processing devices that are linked through a communications network. In a distributed computing environment, program modules may be located in both local and remote computer storage media including memory storage devices.

[0035] Although the computer **328** is shown as having a generalized memory, it may include a variety of computer-readable media. By way of example, and not limitation, computer-readable media may comprise computer storage media and communication media. The memory may include computer storage media in the form of volatile and/or nonvolatile memory such as a read only memory (ROM) and random access memory

(RAM). A basic input/output system (BIOS), containing the basic routines that help to transfer information between elements within computer **328**, such as during start-up, is typically stored in ROM. The RAM typically contains data and/or program modules that are immediately accessible to and/or presently being operated on by the processing unit. By way of example, and not limitation, the computer **328** also comprises an operating system, application programs, other program modules, and program data.

[0036] The components shown in the memory may also be included in other removable/nonremovable, volatile/nonvolatile computer storage media. For example only, a hard disk drive may read from or writes to nonremovable, nonvolatile magnetic media, a magnetic disk drive may read from or writes to a removable, nonvolatile magnetic disk, and an optical disk drive may reads from or writes to a removable, nonvolatile optical disk such as a CD ROM or other optical media. Other removable/nonremovable, volatile/nonvolatile computer storage media that can be used in the exemplary operating environment include, but are not limited to, magnetic tape cassettes, flash memory cards, digital versatile disks, digital video tape, solid state RAM, solid state ROM, and the like. The drives and their associated computer storage media discussed above and illustrated in FIG. 3, provide storage of computer-readable instructions, data structures, program modules and other data for the computer **328**.

[0037] In operation, the apparatus thus described may be used to determine the acoustic velocity, and other physical properties, of various fluids in chamber **300** up to about 400° F and 25,000 psi with improved accuracy over conventional tools. The various fluids include, but are not limited to, reservoir hydrocarbons and other types of miscible

fluids and multi-phase immiscible fluids. If a single-phase miscible fluid is preferred, either reflector **316** or **416** may be used to mix or agitate the fluid sample as necessary to maintain a homogenous solution. This may be accomplished using two independently driven electromagnetic coils. For example, a first coil **340** and a second coil **342** are used in the embodiment illustrated in FIG. 3. Each coil **340** and **342** separately circumscribe chamber **300** to form at least one complete loop. Each coil **340** and **342** may be coupled with a power source using cable **330**, which may be the same power source used to drive the transducer **312**. By alternating power to each coil **340** and **342**, the reflector **316** or **416** may be manipulated within chamber **300** due to the material properties of the reflector. The process of repeatedly manipulating the reflector is thus, used to mix the fluid sample. The manipulation of the reflector may also be used in determining the volume, viscosity and bubble point pressure of the fluid sample as described further in reference to FIG. 5.

[0038] A flowchart in FIG. 5 illustrates one embodiment of a method for operating the apparatus described in reference to FIG. 3. In step **500**, the distance (D) between the first reflective surface **318** and the second reflective surface **320** may be calibrated based upon a known coefficient of thermal expansion for the material comprising the reflector **316** at a predetermined temperature and pressure of the fluid sample in chamber **300**. This distance (D), however, may not need to be calibrated depending on the material comprising the reflector **316** or **416.**

[0039] In step **502,** the transducer **312** transmits an acoustic signal. As the signal leaves the transducer **312**, it radiates in multiple directions as it moves through the fluid in

chamber **300.** Path **332** defines movement of the acoustic signal as it leaves the transducer **312** and is reflected off of the first reflective surface **318** and returns to the transducer **312**. Path **334** defines movement of the acoustic signal as it leaves the transducer **312** and is reflected off of the second reflective surface **320** and returns to the transducer **312**. Path **336** defines movement of the acoustic signal as it passes through opening **322** and is reflected off of piston **304** and returns to the transducer **312**. In each case, the reflector **316** is substantially stationary, however, may be moved away from path **336** as explained below.

[0040] As the acoustic signal travels along paths **332, 334,** and **336,** the reflections of the acoustic signal are detected by the transducer **312** in step **504**. Based upon the time of flight it takes for the acoustic signal to traverse each path **332, 334,** and **336,** the acoustic velocity, volume and density of the fluid sample in chamber **300** may be determined in step **506**.

[0041] The acoustic velocity of the fluid sample in chamber **300** may be determined at a predetermined temperature and pressure ($Vel._{T,P}$) by:

$$Vel._{T,P} = D_{T,P} \div .5 \times (T_2 - T_1)$$

where $D_{T,P}$ is the calibrated distance (D) at the fluid sample temperature and pressure; T_2 is the time of flight for the acoustic signal to travel along path **334**; and T_1 is the time of flight for the acoustic signal to travel along path **332**. This calculation may be repeated using multiple signals, resulting in a repetitive acoustic wave, for more accurate results. The oscilloscope **326** displays an image of the detected reflections, making T_2 and T_1

easily determinable by use of the oscilloscope **326** and/or computer **328**. Acoustic velocity measurements of water using this method have been discovered to agree to within +/- .5% of acoustic velocities quoted in the *AGU Reference of Physical Constants.*

[0042] Once the acoustic velocity ($Vel._{T,P}$) is known, the fluid sample volume at the predetermined temperature and pressure ($Vol._{T,P}$) is determined by:

$$Vol._{T,P} = (.5 \times T_3 \times Vel._{T,P}) \times (\pi \times R^2)$$

where T_3 is the time of flight for the acoustic signal to traverse path **336,** and R is the piston radius. In order to reduce the possibility of error when measuring T_3, the reflector **316** or **416** should be positioned away from path **336**. For example, any surface of the reflector **316** or **416** that obstructs path **336** may produce erroneous results for T_3. This may be accomplished by moving the chamber **300** and/or charging the first coil **340** to attract the reflector **316** or **416** away from path **336**.

[0043] Once the fluid sample volume ($Vol._{T,P}$) is known, the density of the fluid sample at the predetermined temperature and pressure ($Den._{T,P}$) is determined by:

$$Den._{T,P} = M \div Vol._{T,P}$$

where M is the known mass of the fluid sample in chamber **300.** Additional reflective surfaces may be used to measure the time of flight (T_N) for an acoustic signal in each phase of an immiscible fluid sample and/or to test homogeneity.

[0044] Viscosity, a fluids resistance to flow, may also be determined using the first coil **340** and the second coil **342**. In step **506**, for example, the reflector **316** or **416** may be

manipulated between a predetermined first position and a predetermined second position in the chamber **300** by alternating power between the first coil **340** and second coil **342.** As the reflector **316** or **416** moves within chamber **300** due to the magnetic forces imposed by the first coil **340** and the second coil **342,** the distance between the first predetermined position and the second predetermined position will become apparent to those skilled in the art of using an oscilloscope. The time it takes for the reflector **316** or **416** to move between the first position and the second position is determined by the difference (ΔT) between a time of flight for an acoustic signal to reflect off of the reflector **316** or **416** and return to the transducer **312** at the first position and at the second position. The velocity of the reflector **316** or **416** as it moves through the fluid is therefore, the distance between the first position and the second position of the reflector **316** or **416** divided by ΔT. The viscosity of the fluid may be determined from the velocity of the reflector **316** or **416** and its known physical properties using techniques well known in the art. This technique provides an improved viscosity profile without the necessity of complex and expensive timing circuitry. Moreover, this technique may be performed at *in situ* locations that may otherwise preclude the use of complex lab equipment.

[0045] The foregoing apparatus and methods for determining various physical properties of the fluid sample in chamber **300** were experimentally tested as further described in the following example.

EXAMPLE 1

[0046] In this example, the apparatus described in reference to FIG. 3 was used in a laboratory set-up to analyze a crude oil fluid sample having a mass of 49.8710 grams at a temperature of 242° F. The chamber containing the crude oil sample was subjected to various pressures as shown in Table 1 below, each pressure (Column 1) being represented in pounds per square inch. At each pressure, an acoustic signal was transmitted through the crude oil sample and reflections of the acoustic signal off of the reflector (ring) and piston were detected, recorded and used to compile Table 1. The velocity of the acoustic signal in the crude oil sample at each pressure ($Vel._{TP}$) is represented in feet per second (Column 2); the density of the crude oil sample at each pressure ($Den._{TP}$) is represented in grams per cubic centimeter (Column 3); and the volume of the crude oil sample at each pressure ($Vol._{TP}$) is represented in cubic centimeters (Column 10). The distance (D) is 1.503 inches, which represents the distance between the first reflective surface and the second reflective surface. T_1 and T_2 are represented by the ring top (Column 6) and the ring bottom (Column 7), respectively, in microseconds. T_3 is represented by the piston (Column 8), also in microseconds. The cylinder position (Column 9) represents the distance, in inches, between piston **304** and the transducer **312**, which is based upon the corresponding pressure and velocity figures in Columns 1 and 2. The cylinder position is used to determine the crude oil sample volume, which was adjusted using a volume correction factor of 9.4136 c.c. at each pressure.

[0047] Based upon the velocity, volume and/or density of a crude oil sample at a predetermined temperature and pressure, its compressibility and adiabatic compressibility

may also be determined. The compressibility of a crude oil sample is a fundamental component in determining reservoir quality. Applying pressure to a crude oil sample reduces its volume. Conversely, the application of pressure to a crude oil sample will increase its density as reflected in Table 1.

TABLE 1

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10
psi	*Velocity (ft/sec)*	*Density (gm/cc)*	*Compressibility (dV/dpsi)1/Vo*	*Adiabatic Compressibility (1/psi)*	*Ring Top (usec)*	*Ring Bottom (usec)*	*Piston (usec)*	*Cyl. Position (in.)*	*Volume (cc)*
19951	5205	0.7445	3.91E-06	3.67E-06	91.68	139.6	142.9	4.4760	66.9845
19054	5132	0.7416	4.20E-06	3.79E-06	93.76	142.4	145.8	4.4966	67.2498
17922	5035	0.7376	4.51E-06	3.96E-06	96.64	147.1	149.6	4.5245	67.6083
16981	4952	0.7342	4.84E-06	4.11E-06	99.28	149.7	153.2	4.5494	67.9289
16023	4865	0.7304	5.22E-06	4.29E-06	102	153.3	157	4.5767	68.2795
14981	4766	0.7260	5.67E-06	4.49E-06	105.5	157.7	161.6	4.6088	68.6925
14072	4675	0.7219	6.18E-06	4.69E-06	108.6	161.9	165.8	4.6392	69.0840
13019	4566	0.7167	6.81E-06	4.96E-06	112.6	167.2	171.3	4.6778	69.5802
11973	4452	0.7112	7.56E-06	5.25E-06	117	174.1	177.2	4.7203	70.1268
11063	4348	0.7058	8.44E-06	5.55E-06	121.4	178.7	183	4.7613	70.6549
9995	4218	**0.6990**	9.59E-06	5.96E-06	126.9	187	190.2	4.8155	71.3511
8946	4081	0.6914	1.11E-05	6.43E-06	134.4	195.3	198.9	4.8765	72.1357
7995	3948	0.6836	1.26E-05	6.95E-06	141	204.2	207.9	4.9404	72.9578

[0048] Compressibility (Column 4) is determined by:

$$Com.= (Vol._{T,P1} - Vol._{T,P2}) \div (P_1\text{-}P_2 \times 1/Vol._{T,P1})$$

where Vol. $_{T,P1}$ is the initial volume of the crude oil sample at a predetermined temperature (T) and pressure (P_1); Vol. $_{T,P2}$ is the volume of the crude oil sample at the same temperature (T) but a different pressure. (P_2). Adiabatic compressibility (Column 5) may also be useful for reservoir management and is determined by:

$$Com.= \sqrt{Vel._{T,P}} \div Den._{T,P}$$

where $Vel._{T,P}$ and $Den._{T,P}$ have been previously calculated. Power law adjustments were applied to the data illustrated in Table 1 in order to render a linear plot of the data. The results, illustrated by this example and others, reveal that the apparatus and techniques used herein to determine density ($Den._{T,P}$) are more accurate than measurements of density using a pycnometer, which was determined to include a margin of error of about -.39%

[0049] The bubble point pressure, representing the pressure at which a gas bubble begins to form on top of a crude oil sample containing dissolved gases, plays a significant role in reservoir management. For example, crude oil samples obtained at pressures below the bubble point pressure often yield greater volumes of gas than crude oil. The bubble point pressure may be measured by compressing a crude oil sample to a pressure above its bubble point and then slowly reducing its pressure and observing (visually or by using compressibility results) when and where gas bubbles begin to form. Because an accurate bubble point pressure may only be determined by agitating or mixing the crude oil

sample, the apparatus described in reference to FIG. 3 and its *in situ* applications are well suited for bubble point pressure measurements.

[0050] The present invention therefore, provides an accurate and efficient determination of fluid properties for fluid characterization and quantitative interpretation without requiring calibration due to dynamic chamber dimensions. Those skilled in the art of oil and gas exploration will appreciate that the *in situ* application of the present invention may be used for quantitative interpretation of seismic activities, such as amplitude calibrations and estimates of hydrocarbon potential. Other benefits that will be apparent include:

i) contemporaneous analysis with fluid sample extraction;

ii) no dependency on handling, transport and export;

iii) more accurate determination of compositional gradients due to fluid characterization at closer intervals;

iv) cleaner samples as a result of more accurate correction for mud filtrate invasion on formation fluid sample measurements;

v) input for gassmann fluid substitution equations;

vi) determination of when the fluid samples are clean enough for testing;

vii) monitoring dependency of fluid sample on temperature and pressure, which may contain important information for 4D calibrations;

viii) measurement of acoustic properties at reservoir temperature as a function of decreasing pressure, which provides an excellent estimate of the bubble point pressure of crude oil;

ix) immediate detection of heavy component (asphaltene) dropout thus, preventing costly analysis on altered samples;

x) synergy with other results from optical, acoustical, olfactory, capillary pressure and NMR devices;

xi) potential viscosity and permeability measurements; and

xii) restoration of the fluid sample to its *in situ* state, if necessary, and comparison of the *in situ* state with its restoration properties.

[0051] The present invention, as described in reference to FIG. 3, may be easily incorporated into the design of the fluid sampling device illustrated in FIGs. 1 and 2. Referring to FIG. 2, the accumulation chamber **30** comprises a cylinder wall **42** that encloses a cylindrical volume **50** between opposite cylinder and plugs **47** and **49**. Within the cylindrical volume **50** are two free pistons **54** and **56**. The free pistons **54** and **56** divide the cylindrical volume **50** into three variable volume chambers **60, 62,** and **64**.

[0052] The formation sample chamber **64** may, for example, communicate with a valve control formation fluid transfer conduit **70** from the formation pump **19** that is connected through the cylinder in plug **47**. An agitation ball **55** is placed in sample chamber **64** upon final assembly. The wellbore chamber **60** may receive a conduit **76** having an uncontrolled reversible flow communication with the wellbore annulus. The intermediate chamber **62** between the pistons **54** and **56** may be charged with a suitable gas through conduit **86** and the piston **54**. The conduit **86** includes a check valve **88** in series with a valve or plug **89** set within a piston boss **58**.

[0053] The cylinder end plugs **47** and **49** make a sealed interface with respective retainer sleeve **68** and **69**. The end plug **49** is removed from the cylinder end for connection access to the piston conduit **86**. When the intermediate volume **62** is charged with gas,

the gas pressure drives the pistons **54** and **56** against the opposite limits sleeve **68** and **69**. When the gas charge is complete, the charging conduit is removed from the piston conduit **86**. The check valve **88** prevents an exhaust flow of gas from the volume **62** until the conduit **86** is secured by the valve **89**. The cylinder sample chamber **64** is finally closed by assembling the end plug **49**. The end plug is penetrated by the wellbore fluid conduit **76**.

[0054] The mixing ball **55** in FIG. 2 may be replaced with the reflector **316** in FIG. 3. The transducer **312** may be positioned on the piston **56** in FIG. 2 or the plug **47** in FIG. 2. Alternatively, a separate transmitter and receiver may be positioned on the piston **56** or the plug **47**, respectively, or vice versa. Nominal modifications to the plug **47** and/or the piston **56** may be necessary and apparent to those of ordinary skill in the art. The remainder of the sampling tool illustrated in FIG. 2 may be modified by linking the pulsar/receiver **324** with the cable **12** in FIG. 1 to transmit acoustic data from the transducer **312** up the wellbore to the surface for review and analysis. Accordingly, the device illustrated in FIG. 2 already provides a means for maintaining the fluid sample in chamber **64** at *in situ* conditions thus, requiring only slight modifications to incorporate the necessary components for determining various acoustic properties of the fluid sample in chamber **64**. Additionally, the servo motor **310** may be eliminated, and the piston **304** and chamber **300** may not need to be insulated.

[0055] In summary, the present invention permits real-time characterization of fluid properties in a variety of applications at *in situ* conditions. The present invention has therefore, been described in relation to particular embodiments, which are intended in all

respects to be illustrative rather than restrictive. Alternative embodiments will become apparent to those skilled in the art to which the present invention pertains without departing from its scope.

[0056] From the foregoing, it will be seen that this invention is one well adapted to attain all the ends and objects set forth above, together with other advantages, which are obvious and inherent to the apparatus and method. It will be understood that certain features and sub-combinations are of utility and may be employed without reference to other features and sub-combinations. This is contemplated and within the scope of the claims.